Reshaping the decision chain to manage sustainable electric distribution systems: Lessons from Wallonia's GREDOR project

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Abstract

This paper summarizes the lessons learned during the GREDOR project, a four-years research project funded by the Public Service of Wallonia (Belgium), Department of Energy and Sustainable Building. The lessons are summarized in terms of the project organization, proposed algorithmic solutions for technical problems together with the results, and observations and recommendations to the governmental bodies and energy regulator. The project consortium is carefully composed so the partners represent major stakeholders acting on electric distribution systems supported by two research institutions and an engineering solution provider. The composition allows reconciliation of conflicting objectives among different stakeholders in order to define their interactions and help governmental and regulatory bodies to set the rules. The focus of this project is on the distribution system operators with the objective to define their optimal investment, operation, and real-time control while taking into account the objectives and practice of other stakeholders acting on their systems. The aim is to find the optimal global societal benefit. A standard test system and a model of apart of real-life system in Belgium are used to illustrate proposed algorithmic solutions for technical problems. Some of developed IT solutions are designed as open tools available for the use by all interested in similar problems.

Index Terms

Electric distribution system, interaction model, investment, operational planning, real-time control.

I. Introduction

New energy sources (notably renewable ones), new types of the loads (electric vehicles, heat pumps, etc.) and possibilities to use demand as a system reliability resources, created new research and development opportunities all around the World. In Europe, according to the report of 2014 [1], from 2002 until 2014 a total of 459 project were launched with investment of about 3.15 billion EUR. In the Belgian Walloon Region political willingness already exists for some time with clear objectives to increase penetration of renewable generation and redefine existing practices of network system operators (seven distribution system operators are active in Wallonia: ORES, RESA, Régie de Wavre, AIESH, AIEG, Gaselwest, and PBE) in order to maximize societal benefits. In order to define its energy strategy over next 15-20 years, the Walloon parliament, through its government and their body Service Public de Wallonie (SPW, the Public Service of Wallonia), is very active and about 46 million of EUR was invested since 1999 (out of which 22.65 millions of EUR in the period of 2012-2014) in the projects related to electric power and storage technologies. The GREDOR project (French acronym for Gestion des Réseaux Electriques de Distribution Ouverts aux Renouvelables) [2] is one of the major. This project is organized as a four year research project composed of institutions offering different and compatible expertise in the field. The project consortium includes: two universities (the University of Liège and University of Mons), an engineering solution provider company (Tractebel), two distribution system operators (ORES and RESA), ELIA (Belgian TSO), and a retailer (EDF Luminus). Walloon energy regulatory agency (CWaPE) has been actively involved in the project. The project was launched in January 2013 and finished in December of 2016.

This paper summarizes the major results of the project, identifies major achievements and summarizes the recommendations to the governmental and regulatory bodies as the prerequisite for energy activities regulation [3]. The major results are supported by the use of two test systems (a standard 75-bus test system and a part of real-life ORES system). Some of the results are recalled from previous publications stemming from the project while some are not reported previously. These new results include: extension and testing of the global capacity announcement procedure, network reinforcement planning and active network management on real-life distribution system, adaptation of the global capacity announcement procedure and its testing on real-life system for maximum loadability computations.

The paper is organized as follows. First, present situation and current practice in managing distribution systems in Wallonia are reviewed. This is followed by a comprehensive presentation of the project and the results of each stage (interaction models, investments, operational planning, and real-time control). Last section offers conclusions and recommendations.

II. Present situation and practice in Wallonia

In Belgium, off-shore wind and nuclear power plants are governed by the federal government. Renewable energy is governed by the regional governments and their bodies. In the Walloon Region, the generation of electricity through renewable energy plants is promoted with a system of green certificates (allocated by CWaPE) as well as regional support schemes such as investment assistance for companies or for public bodies and net-metering. Developments for renewable energy sources (electricity (RES-E), heating/cooling (RES-H) and transport (RES-T)) at the level of Belgium are coordinated through the so called burden-sharing process in order to meet the requirements of the twenty-first session of the Conference of the Parties (COP 21). The Walloon government introduced the quota system to increase the proportion of renewable energy in total energy generation. One green certificate is issued for every MWh divided by the amount of CO2 saved. The quota for 2015 was set to 27.70% and predicted evolution of the quotes is shown in Fig. 1 for the period 2015-2020 [4].

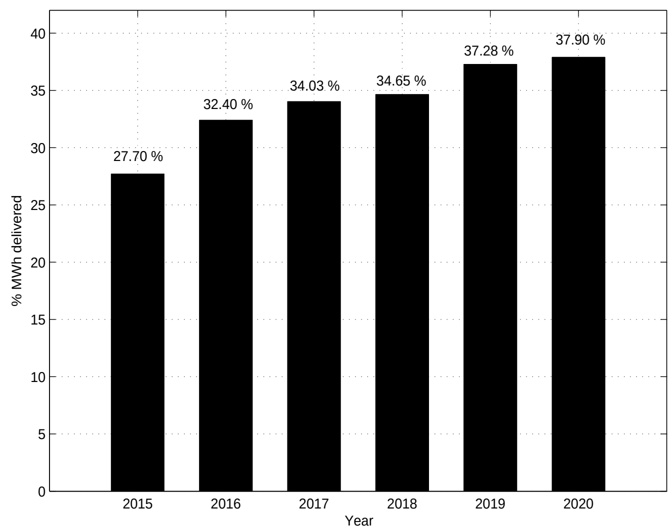

Fig. 1: Nominal quota for green certificates [4].

Present situation in Wallonia in terms of installed RES-E capacities is displayed in Table I [5], [6], [7], [8].

TABLE I: RES-E installed capacities (June of 2016) in MW

Wind	PV (MW-peak)	Hydro	Biomass
1046.0	838.0	110.8	271.0

In 2015 total electric energy consumption in the Walloon region was 16.16 TWh out of which 24% was furnished by RES-E [4].

In order to reach the target for the year of 2020, set for Wallonia to be 12.5% of the total energy consumption (electricity, heating/cooling and transport), the Walloon energy ministry has adopted a mean value of an annual increase of approximately 500 GWh per year between 2015 and 2024 for RES production [9] including annual targets for wind energy, corresponding to about 130 MW of added capacity per year between 2016 and 2020 [10].

As of July 2016, the network operators in Wallonia have a legislative framework that is not complete. There have been two decrees of the Walloon region government [11], [12] that roughly describe the rights and responsibilities of system operators (distribution (DSO) and transmission (TSO)) regarding connection of distributed generations (set in line with the relevant European Commission documents [13], [14], [15] and roadmap [16]). The decrees define two important principles. *The first principle* is that producers should be financially compensated for modulation of the production in case of congestion in the network. This right to compensation, by the network system operator, is subject to the following conditions:

- the generation has to be with renewable source,
- the generation capacity is higher or equal to 5 KVA and connected to Medium voltage (MV) or high voltage (HV) network,
- the network system operator does not apply the measures provided in case of emergency,
- if the connection and/or the required generation capacity, above the immediately available, is deemed economically justified in terms of cost/benefit analysis.

The last condition introduces the *second principle* of economically justified. If the system operator cannot accept all of the capacity, required by a developer, and the connection in question is considered, in whole or in part, economically justified on the basis of the study, the network operator makes the necessary investments. The compensation for capacity limitation will not be due during the period of adaptation of the network beyond the immediately available capacity injection. This limitation is capped at five years and the period may be extended by a reasoned decision of the regulator when the delay in adapting the network is due to circumstances that the network operator does not control.

Nevertheless, the practical arrangements for application of above principles are still missing. However, some rules already emerge. For a generator connected to the DSOs network, it can be summarized as follows:

- DSO fixes, in cooperation with the TSO, the (immediately) available capacity injection (called permanent injection capacity) before and after economically justified investments. If the capacity required by the developer exceed this capacity, the rest of the capacity is called flexible. It does not give the right to financial compensation.
- In case of congestion in the TSO network, the DSO is responsible for translating the congestion order from the TSO to the distribution connected generators. This translation has as objective to minimize the cost of the compensation.
- DSO calculates the volume of energy not produced and, if needed, the volume that would be financially compensated.
- The compensation includes price of energy and green certificates. The quantity of green certificates is determined by other legislations, depending on several regimes (by primary energy sources, age, etc.). Green certificates have a minimum regulated price of 65 EUR per generator connection.
- The case of emergency is limited to 6 hours.

DSOs of the Waloon region exercise static approach to network planning. They check the operational security limits for the peak loads (maximum of consumption and minimum of embedded generation) and for the valley loads (minimum of consumption and maximum of embedded generation). If one of the operational security limits is reached or exceeded, after a risk assessment, investment scenarios are studied with the aim of minimizing the reinforcement cost (capital (CAPEX) and operational (OPEX) expenditure) and proposed to the budget deciders. Planning at the distribution level is structured into two main stages that influence each other:

- Substation planning, which is the link between transmission and distribution, as it defines sitting and sizing needs for primary substations. Depending on operator practices, substation planning may be performed in cooperation of transmission and distribution operators.
- Feeder planning is a two stage process, including planning of distribution feeders in conjunction with the substations and planning of detailed layout of feeders and specification of feeders.

Distribution systems are not independent from the transmission systems. The distribution master plans have to be aligned with the transmission master plans. The structure and planning of the transmission systems is crucial for distribution system planning, and is not treated separately. Therefore, the transmission planning engineers collaborate with the distribution planning engineers on a regular basis to develop their grids and seek the global technical and economical optimum.

Within distribution systems, the location of substations influences feeder design. Conversely, required feeder routes (to serve all customers) can also influence substation sitting and sizing. The distribution planning problem is addressed in a multi-stage manner to reduce complexity, making it more tangible. To alleviate the complexity of the problem, the high level planning of substations and sub-transmission grid is addressed first. Afterwards, distribution planning may be completed with feeder planning, considering also the sitting and sizing of medium voltage/low voltage (MV/LV) transformers. As the steps are interdependent, iterations are needed to arrive at a good solution. Walloon DSOs typically operate 15 kV networks (6, 11 or 13 kV may also be found in older networks but tend to disappear gradually). Currently, the maximum transformation power for 15 kV MV network at the primary substation is 50 MVA. For reliability purposes there are typically two power transformers connected to a MV bus bar. The DSO then builds its networks starting at these bus bars and creates a backbone with some reconfiguration capability. In the backbone there are secondary substations with a more or less high degree of automation and remote control. The MV network is normally operated in radial configuration.

III. The GREDOR project approach

The project focus is on DSO. Since a DSO is one of many actors it is important to address interactions of DSO with other stakeholders acting over the network it operates. The research is organized around four major tasks of different planning horizons (from long to very short term):

- Interaction model,
- Investments planning,
- Operational planning, and
- Real-time control.

The overall approach is depicted in Fig. 2.

Interaction model stage aims at defining the relationships between the actors of an electric distribution system and how they should interact technically and financially to achieve the societal objectives, fostering demand and distributed generation flexibility on one hand and ensuring compatibility with scenarios to be considered for the evolution of the system in the future.

Investment is a long-term planning with the objectives to derive new optimal planning strategies. The link with the operational planning is considered: when searching for the optimal future network, the optimal operation planning is taken into account. The investment planner can for instance decide to invest in communication infrastructure and flexibility contracts, instead of investing in cables. Scenarios defined in the interaction model part are used as inputs to this task.

In the context of a distribution system, operational planning means deciding in advance when and how to use the flexibility and storage means, so that it is always possible to balance consumption and generation. Furthermore, operational planning must be coordinated with real-time control.

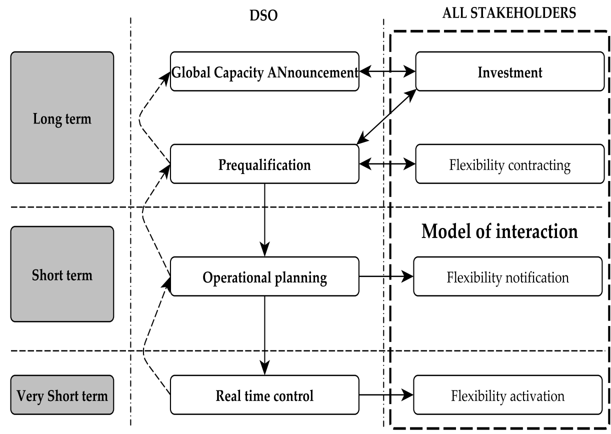

Fig. 2: A process adopted in the project.

Real-time monitoring and control is the last resort to protect the system against unexpected events. This involves estimating the current operating conditions from the available real-time measurements or the use of dedicated measurements. Due attention has to be paid to the control of the distributed generation units, flexible loads, load tap changers, energy storage, or shunt capacitors in a smooth and coordinated manner in order to automatically correct (thermal) congestions and voltages outside their pre-defined limits.

As illustrated in Fig. 2, prequalification is an integral part of long-term planning. It includes a set of procedures, studies and requirements for each particular service.

Note that the information is fed back all the way from real-time control to long-term planning. For example, real-time control feeds back information to the operational planning in the form of statistics about the system limits violations so operational planning problem could be modified if deemed necessary. Similarly, operational planning feeds back information to the prequlifications on problems with feasibility of some system scenarios, etc.

Each task involves a set of technical problems to be solved. Algorithmic approaches adopted to solve problems in all the stages, together with approaches to deal with uncertainties introduced by RES-E, are listed in Table II.

TABLE II: Algorithmic approaches and uncertainties handling

Stage	Algorithmic framework	Dealing with uncertainties
Interaction models	Multi-agent simulation	Scenario generation
Investments	Multi-step optimization	Scenario generation
Operational planning	Markov Decision Process (MDP)	Scenario generation + receding horizon
Real-time control	Multi-step optimization	Receding horizon approach

More details about adopted approaches are provided in the remaining of this paper, together with results using test systems.

A. Test systems

Several standard test systems were used to demonstrate developed methodologies and compare them with previously proposed approaches. In addition a part of real-life, realistically sized, system (part of the ORES system) was used to validate proposed technical solutions. Throughout of this paper the results correspond to so-called standard 75-bus system and a part of the ORES system termed Ylpic. One-line diagrams of these systems are shown in Fig 3 and Fig 4.

The main characteristics of these systems are summarized in Table III presenting: nominal voltage V, number of buses (substations) n_b, number of lines n_l, number of generators n_g, total active load power P_l, total reactive load power Q_l, and total generation active power P_g (for Ylpic system the powers correspond to their maximal values for both generation and load, existing four generators are marked as ”Ge”).

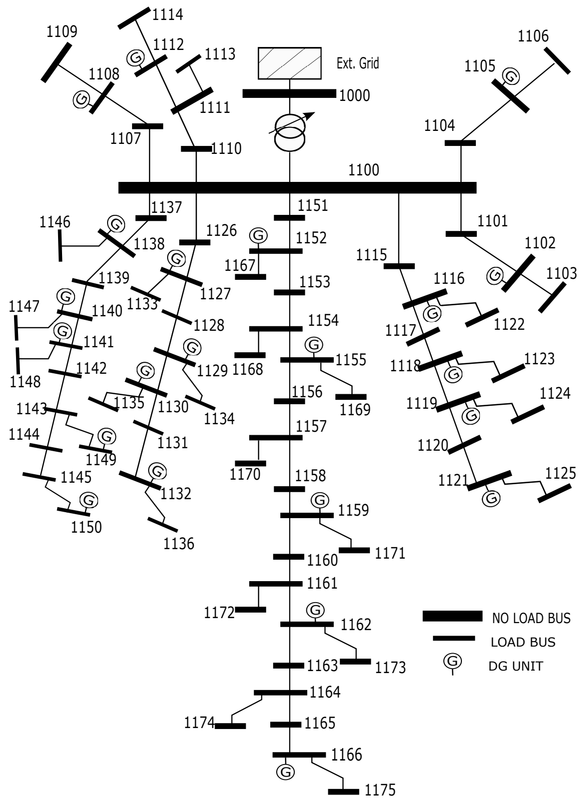

Fig. 3: 75-bus standard test system.

TABLE III: Characteristics of test systems

System	V kV	n_b	n_l	n_g	P_l MW	Q_l $MVAr$	P_g MW
75-bus	11.00	77	75	22	4.86	0.97	38.06
Ylpic	10.00	328	337	4	20.00	8.45	12.50

B. Interaction models

The GREDOR approach to this problem is simulation based one. Based on the simulations the conclusions and recommendations are made on all interaction models emphasizing their advantages/disadvantages. The choice of simulation based approach to exercise interaction models is justified by the fact that there is no one-fits-all solution to this problem and comparison of different models is right approach to reconcile different objectives of the stakeholders acting on the system. A simulation platform is created to analyse and compare interaction models agreed among the project partners. The platform is designed as multi-agent simulation platform since this simulation framework best fits analysis of different (sometimes conflicting) objectives of stakeholders acting on the system. Each stakeholder is modelled as an agent having its own objective. Some stakeholders are modelled as actors having multiple roles (TSO, DSO, producers, retailers) while others have only a role (balance responsible parties, flexibility service providers, flexibility service users). For example, the TSO is a flexibility service user with given needs of flexibility services. Producers and retailers both act simultaneously as balance responsible parties, flexibility service providers and flexibility service users. Four interaction models are defined as follows [17]:

- **Model 1.** The DSO does not use any flexibility service and allows grid users to produce or consume only in the safe access bounds (determined in prequalification step).
- **Model 2.** The DSO sets full access bounds for each actor but allows access in the requested range (full access plus flexible access). The grid users may be restrained to keep their production/consumption in the range of full access bounds upon request of the DSO. This restriction does not lead to financial compensation by the DSO except for the imbalance created by the request.
- **Model 3.** This model is equivalent to Model 2 but the DSO pays for the activation of the flexibility of the grid users.
- **Model 4.** The DSO does not oblige grid-users to provide flexibility (they can use requested access range). The DSO can, however, contract flexibility like any flexibility service user.

Societal welfare is an important factor to consider in this type of studies. In general it is not easy to reach consensus on what is societal welfare especially given that the stakeholders have conflicting objectives. Definition adopted in the project and extensively used in the analysis of interaction models is a simple one: societal welfare is the sum of the surpluses minus the

Fig. 4: Ylpic system.

costs of all stakeholders. All of the models are simulated under the same conditions for one year. The results of four interaction models comparison, using 75-bus test system, are displayed in Table IV [17].

Model 1 yields no shedding but a lower welfare due to the conservative actions of the DSO to restrict the access of generation units. This conservative strategy penalizes the producers which are not allowed to produce in situations where the network can handle higher injections. Models 2, 3 and 4 lead to equivalent and higher welfares with average shedding penalties of 1000 EUR per day. These models would be more efficient if shedding could be avoided. This necessity is caused by the activation of flexibility services by the TSO in an opposite direction to the directives of the DSO. The DSO activates flexibility services based on the baselines so that once the services are activated, congestion no longer occurs. However, the actual realization differs from the expectation since the DSO is not the only user of flexibility services. A better coordination between the DSO and other flexibility services users would lead to even higher welfare and is necessary to ensure the security of the system over the long term. Only the TSO uses demand side flexibility in considered simulations. Even though flexibility services from the demand side are cheaper, their usage is expensive for the DSO which must compensate the imbalance created to solve a congestion problem. In addition, an activation of an energy constrained flexibility offer in one period requires another activation in a different period and, therefore, up to a double imbalance compensation. In terms of the producers the results of [17] show:

- Model 1 significantly decreases the surplus of each producer,
- the smallest producer is the most sensitive to the choice of the interaction model,
- in Models 2, 3 and 4 the producers may have an incentive to bargain their flexibility for free, as long as the imbalance is paid, in order to obtain an increased access to the distribution network,
- if TSO, DSO and other flexibility service users coordination mechanism is in place to ensure a globally coherent activation of the flexibility it would lead to an interaction model with the largest welfare while avoiding shedding.

Note that in [17] an additional model (termed as Model 1 in [17], where the DSO does not use any flexibility service and does not restrict grid users) was considered for the reference, however this model was not a part of the project.

Model 4 is assumed in the remaining simulations included in this paper and generation and load flexibility whenever used are assumed to be contracted by a DSO.

TABLE IV: Comparison of interaction models over one year (adopted from [17])

	Interaction model				Unit
	1	2	3	4	
Wellfare	27,411	39,868	39,692	39,665	EUR
Shed. cost	0	914	1,077	1,103	EUR
DSO cost	0	443.9	655.7	655.7	EUR
TSO surplus	2,878	2,874	2,873	2,873	EUR
Producers surplus	22,005	37,825	38,024	38,023	EUR
Retailers surplus	527	528	528	528	EUR
Total production	227.33	387.07	386.74	386.69	MWh
Total imbalance	1.40	17.51	17.83	17.88	MWh
Maximum imbalance	-0.13	-2.44	-2.52	-2.53	MW
Total flex. use	14.94	29.44	29.39	29.40	MWh
Total energy shed	0	1.83	2.15	2.21	MWh

The open source code needed to exercise and possible extend interaction models is available at http://www.montefiore.ulg.ac.be/ dsima/.

C. *Investments planning*

From a DSO perspective, since DSO's roles are in the focus of the project, two investment problems are considered: network reinforcement/expansion planning and global capacity announcement. The latter is introduced as the way to reconcile conflicting objectives of a DSO and generation connection developers since within the European regulatory framework DSOs are not allowed to own generation plants and are not entities to conduct optimal generation planning [17].

1) Network reinforcement planning: Tractebel's proprietary tool Smart Sizing is used for this purpose [18]. It aims particularly at the connection to the main transmission network, substation planning and main distribution feeders planning, in order to establish an ideal target network that leads to minimum cost solutions. The outputs of this optimization problem are the optimal sizes of transformers, cables, lines, and the investments in communication technology to exploit the potential load flexibility. This ideal target network can be used to define a subset of investments to be considered for future concrete investment problems. At the heart of the tool lies an optimization routine that minimizes the total cost of the network, i.e. the sum of CAPEX and OPEX over the study horizon while respecting the system constraints and constraints imposed on the flexibility. The CAPEX consists of the cost of electrical equipment, such as cables and transformers, and also of investments in ICT infrastructure. The OPEX consists of the cost of losses and the cost of procuring flexibility. Algorithmic details of Smart Sizing tool are provided in [18]. Table V shows a representative output of the tool.

TABLE V: Representative output of the Smart Sizing tool for Ylpic network reinforcement

	Optimal rating	Optimal size
HV cable	47.72 MW	102.21 mm^2
MV cable	8.47 MW	245.73 mm^2
Transformer	28.04 MVA	-
Flexibility (shifted load)	130.40 $GWh/year$	-

The results reveal that the generation (Wind, PV,CHP) curtailment is economically not beneficial in the Ylpic network (only existing four generators, marked as "Ge", are considered to produce the results, see Fig 4). This is justified by the fact the peak consumption is higher than the peak generation in the network and the option of generation curtailment will bring in no economic benefit. Therefore, out of the available flexibility options, load shifting makes more economic sense.

Investment planning including flexibility (load shifting, generation curtailment and load shedding) requires optimization over full load profile for the planning horizon. The GREDOR project approach is to ease computational burden associated with the optimization problem through the choice of representative days and their corresponding weights and analyse the impact of flexibility for these days taking into account the weights. Representative days are chosen with the objective to capture the salient characteristics of the yearly profiles, namely the peaks and the energy. Nine days are selected as follows:

- Six typical days (Winter weekday, Winter weekend, Summer weekday, Summer weekend, Intermediate season weekday, Intermediate season weekend). These days represents the energy-days which capture the energy of the seasons.
- Positive injection peak day. This day is the one not captured by the energy-days and is intended to capture the load shifting and shedding potential (load flexibility).
- Negative injection peak day. This is the one not captured by energy-days and is intended to capture the generation curtailment potential (generation flexibility).
- The highest peak day of the year. This day can be a positive peak or a negative peak and is intended for the sizing of transformer, cables etc.

Nine representative days are determined, for the final year of planning horizon (2020), and their net injection profiles are shown in Fig. 5 while their weights (equivalent to the number of days they represent) are given in Table VI.

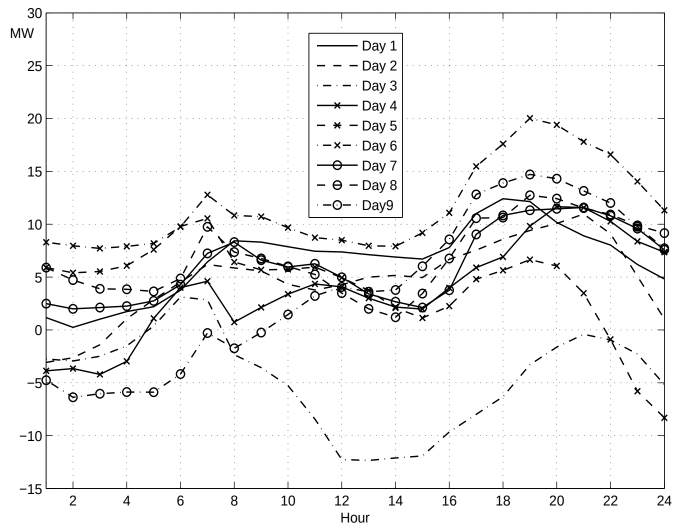

Fig. 5: Nine representative days injection profile (year 2020).

TABLE VI: Representative day weights

Day	1	2	3	4	5	6	7	8	9
Weight	1.0	0.9	0.9	23.3	23.3	116.2	47.4	96.0	56.0

Relative error introduced by using nine representative days with respect to the full load profile of the year is 0.17%. The weights of each representative day (equivalent to number of days they represent) is determined based on their probability of occurrence within the year.

2) Global Capacity ANouncement (GCAN): The GCAN procedure approximately computes the generation connection amount in all or pre-specified system substations, while accounting for the DSO's investment plan and known targets such as renewable penetration and losses [19], [20]. Its purpose is to attract and encourage developers for generation connection projects.

The computations are performed for the future and the results are mapped to the present system situation. The future system situation is created using: long-term prediction of load growth, network reinforcement and expansion plan, target generation penetration level based on regulatory or environmental considerations, target system active power losses as percentage of the total net injections possibly complemented with other targets (power quality requirements, etc.). A DSO commits to compute these amounts with optimal network configuration minimizing annual energy losses [21]. The results of GCAN are computed regularly at each step of planning horizon and updated immediately after a new significantly large connection is realized on the system. The computation is conducted in a receding horizon manner, thus routinely updating or revising the computations taking into consideration more reliable and recent data as they become available. The GCAN approach is illustrated in Fig. 6.

The core computations are performed using a repeated power flow with efficient generation increase direction. An important aspect of repeated power flow (how to increment active and reactive powers) is solved by computing approximate distance

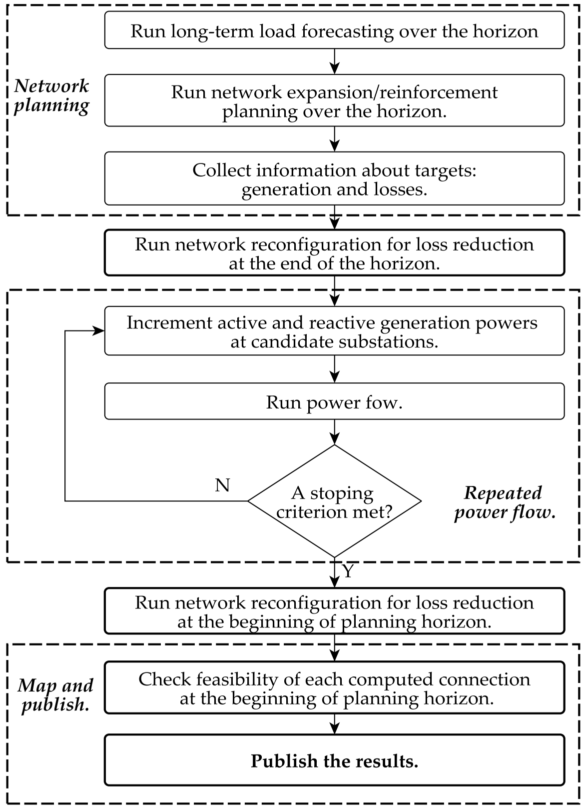

Fig. 6: GCAN computations.

for each substation from the most constraining system limit. If the voltage magnitude is concerning limit then active power increase (for substation i) is computed as,

$$d_i = \left(2V_i \|Y_{i,i}\| + \sum_{j=1, j\neq i}^{n} V_j \|Y_{i,j}\| \right) (V_{i,lim}^{upper} - V_i),\ i \in CSL \tag{1}$$

where $\|Y_{i,i}\|$ is the absolute value of the admittance matrix entry (i,i), V_i the voltage magnitude, $V_{i,lim}^{upper}$ the upper voltage limit (usually set to $1.05pu$) and CSL the candidate stations list.

Reactive powers are incremented in accordance with chosen technology determined by power factor.

More accurate estimations of connection powers can be obtained through a better approximation of injection duration curve for annual losses considerations. The GCAN procedure is further modified by choosing representative days with corresponding weights (period of time that each day represents) in line with the method presented for network reinforcement problem. This modification of GCAN procedure is shown in Fig. 7.

This modification offers better consideration of annual losses at the expense of slightly increased computational burden that depends on the number of representative days. The injection duration curve for Ylpic system, with nine representative days) is given in Fig. 8.

The injection duration curve is computed by averaging the injection for each representative day while duration corresponds to the representative days weights given in Table VI.

Results of GCAN computation for Ylpic system (to be published at the first year of chosen five year planning horizon 2015-2020) are shown in Fig. 9. The results are produced taking into account network reinforcement plan, for the year of 2020, computed in previous section.

Both permanent (black) and flexible (grey) generation connections are shown in Fig. 9. Permanent generation connections are computed for one Summer day with low load and high generation while flexible connections are computed for a Winter day with high load and low generation (see Fig. 8). GCAN shows possibility of 48 new generation connections (substations in grey colour, together with four existing generators marked with ”Ge”, in Fig. 4) totalling 34.32 MW of new generation (all generation units are considered as having power factor equal to 1) out of which 25.61 MW is permanent.

A similar procedure is introduced for maximum loadability computations (useful, for example, to compute capacities in electric vehicles charging station sitting and sizing problem) again as the way to reconcile conflicting objectives among a DSO

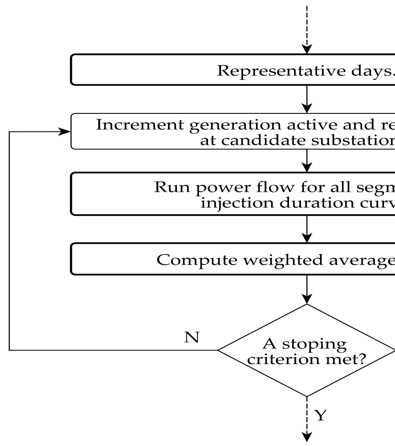

Fig. 7: A modification of the GCAN procedure for annual losses computation based on representative days.

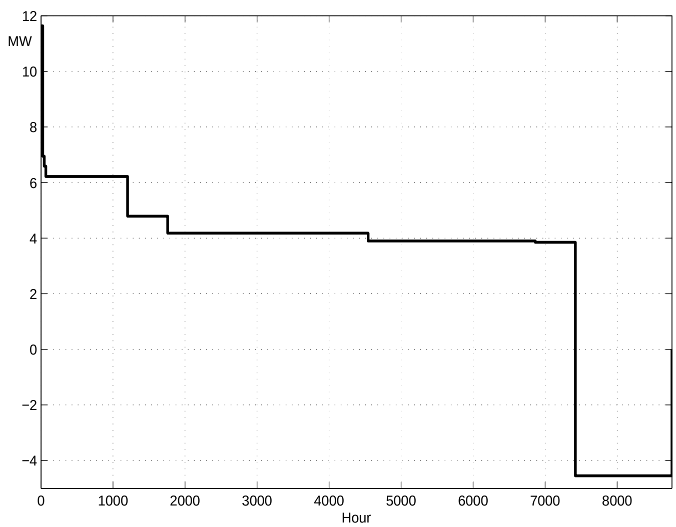

Fig. 8: Injection duration curve approximated by nine representative days for Ylpic system.

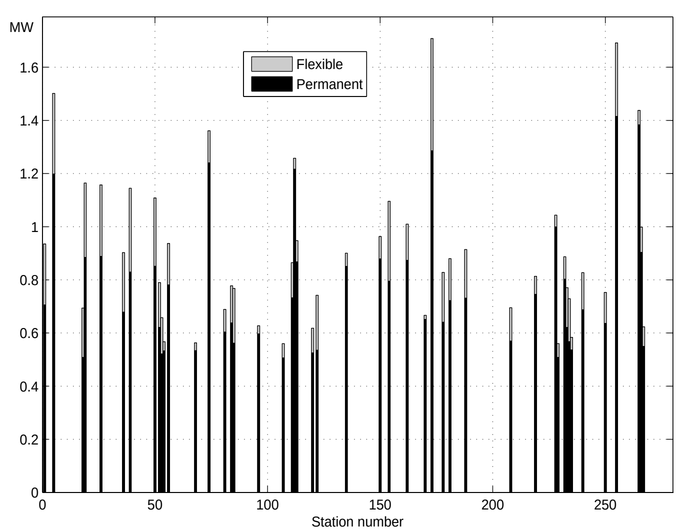

Fig. 9: Generation connections for Ylpic system.

and other actors. In this case the electrical distance for substation i is modified as,

$$d_i = \left(2V_i\|Y_{i,i}\| + \sum_{j=1,j\neq i}^{n} V_j\|Y_{i,j}\|\right)(V_i - V_{i,lim}^{lower}),\ i \in all \tag{2}$$

GCAN procedure, modified to compute maximum loadability, of individual stations is illustrated in Fig. 10 while the results using Ylpic system are presented in Fig. 11.

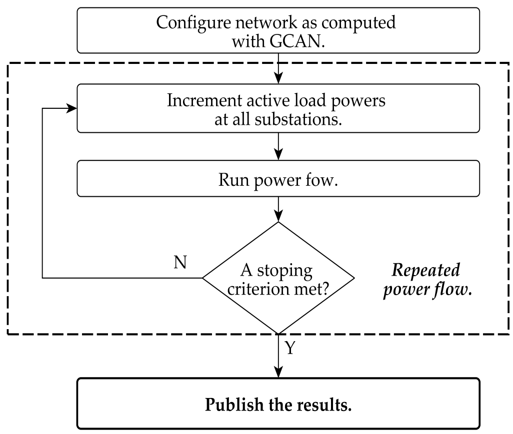

Fig. 10: GCAN variant for maximum loadability computation.

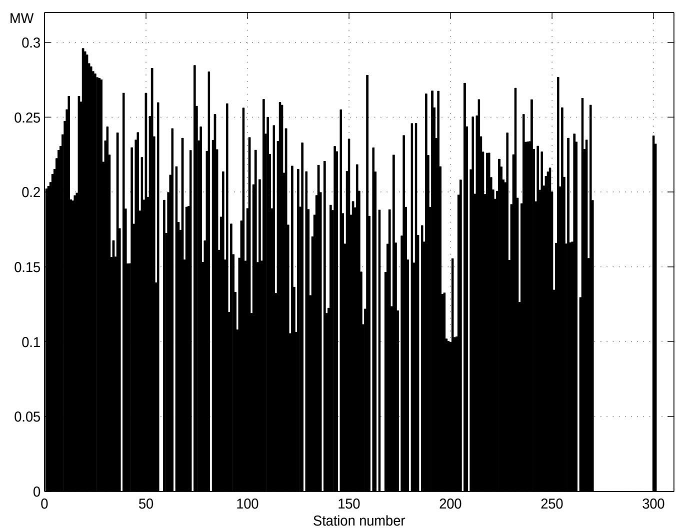

Fig. 11: Maximum loadability for Ylpic system.

Bars in Fig. 11 indicate additional power in MW that can be connected to the stations and are computed for a Winter day with high load and low generation taking into account the results of GCAN computations. Stations with zero additional power are those not considered for any load connection according to the system planning. The results of Fig. 11 are produced as inputs for electric vehicles charging stations sitting and sizing and thus only active power is increased according to eq. 2 (no reactive power increase is considered).

The results of GCAN computations (both variant for generation connection or maximum loadability) are supposed to be made publicly available either directly by DSO or by energy regulator (in tabular or GIS map form). The latter is suggested by project participants as preferred one.

D. Optimal operational planning strategy

Optimal operational planning strategies are short-term policies that control the power injected by generators and/or taken by loads in order to avoid congestion or voltage issues [22], [23]. Naturally, the optimal operational planning is a sequential decision-making problems under uncertainty [22]. The sequentiality of the problem stems from the modulation service that is provided by flexible loads. The problem is also stochastic, because the evolution of the system and the outcome of control actions are affected by several uncertain factors. These factors are the wind speed, the level of solar irradiance, and the consumption level of the loads. The framework for operational planning is illustrated in Fig. 12.

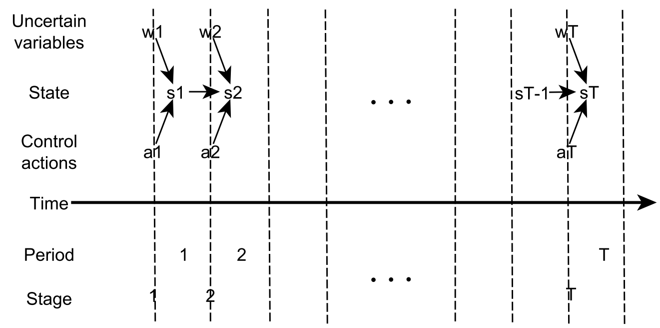

Fig. 12: The framework of operational planning.

Overall planning horizon T is divided in a set of periods separated by decision stages. Within the project the optimal operational planning strategies are pursued through the problem formulation as MDP [23].

At each decision stage, control actions a are applied impacting, together with the uncertain variables w, the system state s. The decisions taken before the time $t < T$ influence the decisions available between times t and T. The state s defines MDP (not to be confused with usual notion of the system state in terms of voltage magnitudes and their phase angles). By definition, the state contains enough information so that knowing the control action at time t and the state at the previous period $t-1$ it is always possible to compute the states at time from t until T. The evolution of the system is thus governed by relation,

$$\boldsymbol{s}_{t+1} = f(\boldsymbol{s}_t, \boldsymbol{a}_t, \boldsymbol{w}_t)\,,. \tag{3}$$

In [23] the state s is defined as the minimal information that is required to know the power injections of the all system devices complemented with the level of solar irradiance and the wind speed. Action vector a includes the maximum level of active power for each of the generators and the activation indicators of the flexibility services of the loads [23]. The problem boils down to finding the system trajectory over the period T with the maximum return. The return over the period of T is defined as discounted sum of rewards obtained from each transition of the system. The reward r is defined as follows,

$$\begin{aligned} r(\boldsymbol{s}_t, \boldsymbol{a}_t, \boldsymbol{s}_{t+1}) = & -\underbrace{\sum_{g\in\mathcal{G}} \max\{0, \frac{P_{g,t+1} - \overline{P}_{g,t+1}}{4}\} C_g^{curt}(\boldsymbol{s}_{t+1}^{(\mathrm{aux})})}_{\text{curtailment cost of DGs}} \\ & -\underbrace{\sum_{d\in\mathcal{F}} act_{d,t} C_d^{flex}}_{\substack{\text{activation cost}\\ \text{of flexible loads}}} - \underbrace{\Phi(\boldsymbol{s}_{t+1})}_{\text{penalty function}}\ , \end{aligned} \tag{4}$$

where $C_g^{curt}(\cdot)$ is a per-generator function that defines the curtailment price, while $C_d^{flex}(\cdot)$ defines the activation cost for each flexible load. The function Φ aims at penalizing a policy that leads the system into an undesirable state and, together with C_g^{curt} and C_d^{flex}, it must be defined when instantiating the decision model.

The return over T periods, is defined as the weighted sum of the rewards that are observed over a system trajectory,

$$R_T = \sum_{t=0}^{T-1} \gamma^t r(\boldsymbol{s}_t, \boldsymbol{a}_t, \boldsymbol{s}_{t+1})\,, \tag{5}$$

where $\gamma \in]0;1[$ is the discount factor.

Because the operation of a distribution system must always be ensured the return over infinite horizon is considered in [23],

$$R = R_\infty = \lim_{T\to\infty} \sum_{t=0}^{T-1} \gamma^t r(\boldsymbol{s}_t, \boldsymbol{a}_t, \boldsymbol{s}_{t+1})\,, \tag{6}$$

Even if the return R is defined as an infinite sum, it converges to a finite value [23]. Starting from an initial state $\boldsymbol{s}_0 = \boldsymbol{s}$, the expected return R of the policy π can be defined as,

$$J^{\pi}(\boldsymbol{s}) = \lim_{T\to\infty} \underset{\substack{\boldsymbol{w}_t \sim p_{\mathcal{W}}(\cdot) \\ t=0,1,\ldots}}{\mathbb{E}} \Big\{ \sum_{t=0}^{T-1} \gamma^t \rho(\boldsymbol{s}_t, \pi(\boldsymbol{s}_t), \boldsymbol{w}_t) | \boldsymbol{s}_0 = \boldsymbol{s} \Big\} \,. \tag{7}$$

A DSO, addressing the operational planning problem, seeks to determine an optimal policy π^* among all the elements of Π, i.e. a policy that satisfies the following condition,

$$J^{\pi^*}(\boldsymbol{s}) \geq J^{\pi}(\boldsymbol{s}), \forall \boldsymbol{s} \in \mathcal{S}, \forall \pi \in \Pi \,. \tag{8}$$

It is well known that such a policy satisfies the Bellman equation [23], which can be written,

$$J^{\pi^*}(\boldsymbol{s}) = \max_{\boldsymbol{a}\in\mathcal{A}_{\boldsymbol{s}}} \underset{\boldsymbol{w}\sim p_{\mathcal{W}}(\cdot)}{\mathbb{E}} \big\{ \rho(\boldsymbol{s},\boldsymbol{a},\boldsymbol{w}) + \gamma J^{\pi^*}(f(\boldsymbol{s},\boldsymbol{a},\boldsymbol{w})) \big\}, \forall \boldsymbol{s} \in \mathcal{S} \,. \tag{9}$$

A scenario tree generation is used to generate and sample system trajectories while scenario clustering is used for computational burden reduction. An example of scenario-tree and their hierarchical clustering is shown in Fig. 13 [23]. A representative results of operational planning, for Ylpic system, with three scenarios and planning horizon set to 10 (with time resolution of 15 minutes), are shown in Fig. 14.

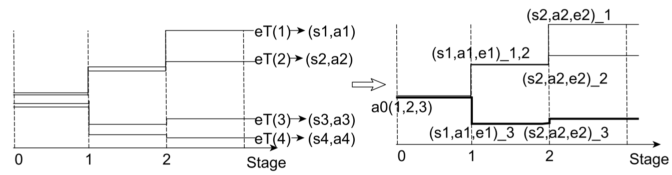

Fig. 13: Scenario tree (left) and hierarchical clustering (right).

The results are presented in terms of total system generation, total load, all system limits (thermal and voltage magnitudes), operational costs, and computational burden at each decision step. These results correspond to the system's expected operating conditions in 2020. Wind and solar distributed generators production is governed by generation data recorded in 2013 in the system surroundings. The available control actions consist of active production, reactive injection set-points, and activation of load flexibility services. The problem is re-formulated as mixed integer non-linear program and solved in receding horizon manner where controls corresponding to the first stage of the horizon are applied and procedure repeated (for details see [23]). Wind and solar generations are considered stochastic (see Fig. 14 between time steps 480 and 490) while the demand is considered to be deterministic due to the lack of real consumption data for the system. The test bed is made publicly available at http://www.montefiore.ulg.ac.be/ anm/ to foster further research and the use of all interested in this type of problems. The test bed includes a simulator of the distribution system, with stochastic models for the generation and consumption devices, and callbacks to implement and test various active network management strategies.

E. Real-time control

The real-time control monitors the system evolution using either dedicated measurements and communications system or the snapshots from state estimation (see Appendix) and correct violations of the system limits if they occur. The approach of the GREDOR project is to use a centralized control scheme based on a multi-step receding horizon optimization formulation of the control problem. This decision is partly driven by preference of two DSOs involved in the project since they are in the stage of communication infrastructure upgrade as pre-requisite for centralized control.

Based on the ideas considered in [24] for transmission system, the control algorithm computes a sequence of control actions over chosen control horizon N_c to control the system evolution over a pre-defined prediction horizon N_p while respecting the system constraints in terms of voltage magnitudes and currents in the lines. It applies only first control actions in computed sequence, collects the system response through the monitoring system and repeats the whole procedure. This feedback brings robustness in the control with respect to always present noise in the measurements and the system model. Furthermore, in order to decrease computational burden a linear prediction model based on power flow sensitivities was proposed in [25]. Several variants of this control was considered with the aim to accommodate different interaction models. A variant of the control presented in this section is illustrated in Fig. 15.

The objective of this variant is to minimize the sum of squared deviations, over the N_c future control steps, between the controls and their references [25] (some of the references are results of the operational planning algorithm),

$$\min_{\boldsymbol{u},\boldsymbol{\varepsilon}} \quad \sum_{i=0}^{N_c-1} \|\boldsymbol{u}(k+i) - \boldsymbol{u}_{ref}(k+i)\|^2_{\boldsymbol{R}} + \|\boldsymbol{\varepsilon}\|^2_{\boldsymbol{S}} \tag{10}$$

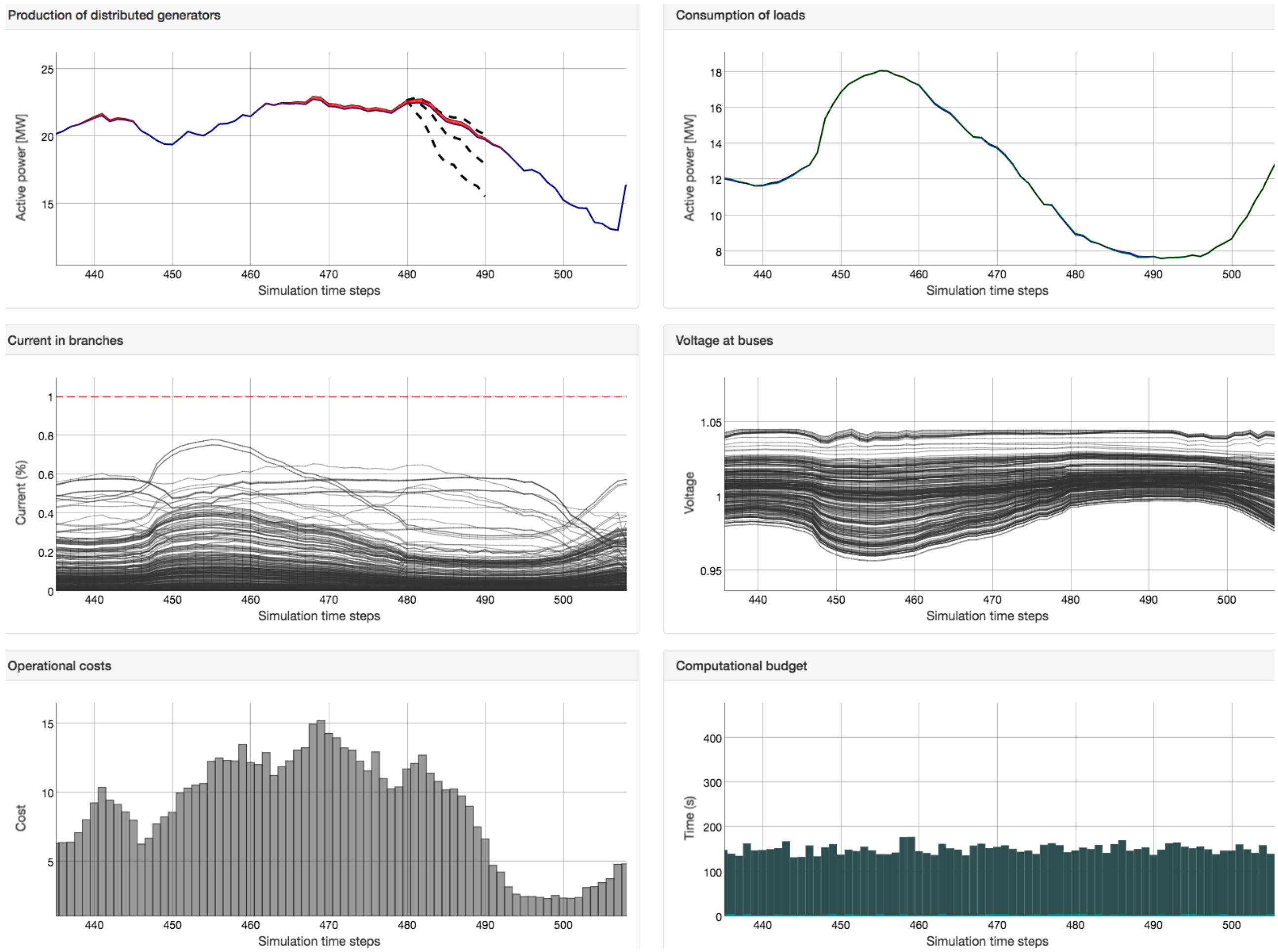

Fig. 14: Representative results of optimal operational planning for Ylpic system.

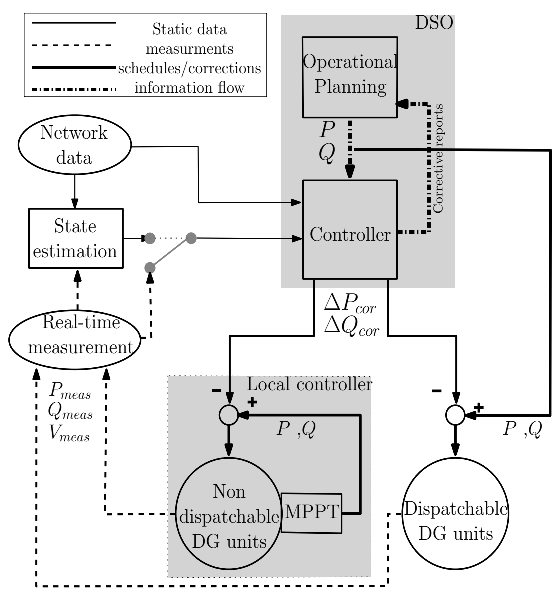

Fig. 15: Real-time control scheme.

subject to:

for $i = 1, \ldots, N_p$,

$$\begin{aligned}\boldsymbol{V}(k+i \mid k) &= \boldsymbol{V}(k+i-1 \mid k) + \\ &\quad + \boldsymbol{S}_V \left[\boldsymbol{u}(k+i-1) - \boldsymbol{u}(k+i-2)\right] \quad (11)\\ \boldsymbol{I}(k+i \mid k) &= \boldsymbol{I}(k+i-1 \mid k) + \\ &\quad + \boldsymbol{S}_I \left[\boldsymbol{u}(k+i-1) - \boldsymbol{u}(k+i-2)\right] \quad (12)\end{aligned}$$

$$-\varepsilon_1 \mathbf{1} + \boldsymbol{V}^{low}(k+i) \leq \boldsymbol{V}(k+i \mid k) \quad (13)$$

$$\boldsymbol{V}(k+i \mid k) \leq \boldsymbol{V}^{up}(k+i) + \varepsilon_2 \mathbf{1} \quad (14)$$

$$\boldsymbol{I}(k+i \mid k) \leq \boldsymbol{I}^{up}(k+i) + \varepsilon_3 \mathbf{1} \quad (15)$$

for $i = 0, \ldots, N_c - 1$,

$$\boldsymbol{u}^{min} \leq \boldsymbol{u}(k+i \mid k) \leq \boldsymbol{u}^{max} \quad (16)$$

$$\Delta \boldsymbol{u}^{min} \leq \boldsymbol{u}(k+i \mid k) - \boldsymbol{u}(k+i-1 \mid k) \leq \Delta \boldsymbol{u}^{max} \quad (17)$$

where $\boldsymbol{R}$ is the diagonal weighting matrix with the purpose to prioritize the controls. The last term in (10) involves the slack variables $\boldsymbol{\varepsilon}$ to relax the inequality constraints in case of infeasibility; the entries of the diagonal matrix $\boldsymbol{S}$ are given very high values.

The objective is minimized subject to the linearized system evolution (to ease computational burden) over the N_p prediction steps using the sensitivities computed from power flow model. $\boldsymbol{V}(k+i \mid k)$ and $\boldsymbol{I}(k+i \mid k)$ are the predicted bus voltages and branch currents, and $\boldsymbol{S}_V$ and $\boldsymbol{S}_I$ are sensitivity matrices of those variables with control changes.The prediction is initialized with $\boldsymbol{V}(k \mid k)$ and $\boldsymbol{I}(k \mid k)$ set to the last received measurements. Voltage magnitude and line thermal limits are imposed as the inequality constraints where $\boldsymbol{u}^{min}$, $\boldsymbol{u}^{max}$, $\Delta \boldsymbol{u}^{min}$ and $\Delta \boldsymbol{u}^{max}$ are the lower and upper limit on the controls and on their rate of change. ε_1, ε_2 and ε_3 are the components of $\boldsymbol{\varepsilon}$ aimed at the constraints relaxation, and $\mathbf{1}$ denotes a unit vector.

Active and reactive powers of dispatchable and non-dispatcable DGs are used as controls. The schedules of dispatchable DGs are known by the controller and treated as known system changes. This information comes from the operational planning decisions. The limits on reactive powers of DGs are updated at each time step based on the measured active power and terminal voltage (see eq. 16).

The case, presented in this paper, involves two successive changes of DG active powers: an unforeseen wind speed change from $t = 20$ to $t = 70$ s increasing the production of the non-dispatchable units, and a power increase of dispatchable units, as known change, scheduled to take place from $t = 150$ to $t = 190$ s. The corresponding active power generations are shown in Fig. 16.

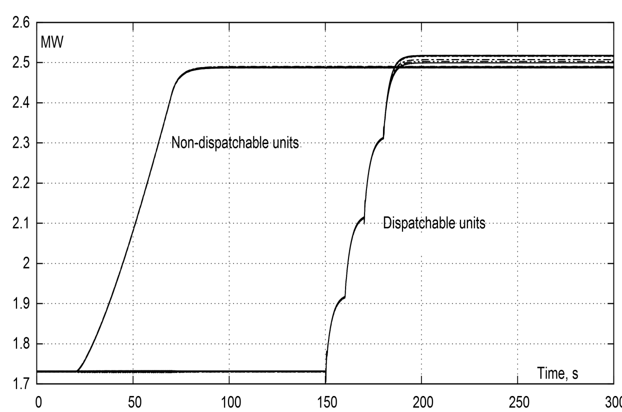

Fig. 16: Active power generation (adopted from [25]).

Figure 17 shows the evolution of several bus voltages. The increase in wind power makes some voltage magnitudes approach the limit. Without corrective actions, the subsequent scheduled change would cause a limit violation. However, this is anticipated by the controller, through the P_{ref} values. Therefore, the controller anticipatively adjusts the DG reactive powers (control of reactive powers are assigned with lower weights and has priority over active power control) with the result that no voltage exceeds the limit, while all the active power changes are accommodated.

The controller anticipative reaction is seen in Fig. 17, where the voltage decrease resulting from the reactive power adjustment counteracts the voltage increase caused by the active power increase.

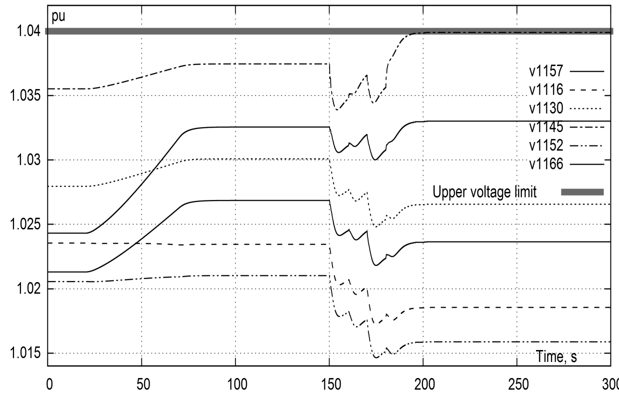

Fig. 17: Bus voltages (adopted from [25]).

Presented results illustrate ability of proposed control scheme to bring the system in normal operation conditions when violation of the system limits appears. This is achieved despite the use of simplified system model thanks to inherent robustness of proposed control with respect to errors in the model due to repeated computations of the controls. This was a driving force to use this type of the control. Moreover, other controls not considered in presented results (LTC, flexible load, shunt capacitors) could be easily included in proposed control scheme and prioritized using appropriate weights while robustness with respect to uncertainties could be further increased by simple re-formulation as chance-constrained programming problem [26].

IV. Conclusion

There is a strong belief the experience from other projects is extremely useful when considering the problems as the ones in the GREDOR project. Consequently, there is a high hope the material presented in this paper provides useful information for all those already involved or in the stage of launching projects to help define their energy strategy related to electricity.

The following conclusions can be drawn:

- Present practice in Wallonia need a considerable re-design to avoid huge investments in distribution networks. The project demonstrated this need and offered solution for practical problems to be used in the re-designing.
- The project results clearly demonstrate how the capacity of existing system can be increased leading to higher penetration of RES-E into distribution systems, thus easing the reach of the overall RES-E targets.
- There is an urgent need for the Wallon Government and energy regulator CWaPE to make decisions and set the rules among different stakeholders. Interaction models considered in the course of the project could make these decisions much easier to make.
- There is an urgent need for new governmental orders to clarify and make practical arrangements of financial compensation and the economically justified investments introduced in existing decrees [11], [12].
- Although efforts were undertaken to make decrees [11], [12] in line with existing European documents more attention should be paid to the use of terminology and make it completely in line with relevant EU documents (an example: permanent injection capacity should be called fixed generation connection capacity).
- DSO engineers prefer approaches that include a transitional solution for technical problems whenever possible. This transitional solution should be focused around existing tools (primarily power flow) even if they offer a suboptimal solution. A good example in the project is GCAN procedure built around repeated power flow solutions.
- It is preferable, in this type of project, to include at least one representative of each stakeholder since only direct interactions to reconcile conflicting objectives could offer maximization of societal welfare.

Major project achievements are summarized as follows:

- GCAN procedure is going to be implemented by two Walloon region DSOs (the two involved in the project) since CWaPE is going to impose the rule on mandatory publication of approximate generation connection amounts. This implies that other DSOs will follow this approach or develop similar methodology.
- Four interaction models were analysed in details and results made available to governmental bodies and CWaPE. This should help setting the rules by these bodies.
- Algorithmic solutions are developed in all segments of the project: model of interaction, investment, operational planning, and real-time control. Some of the tools are made publicly available. Two tools, namely GCAN and time-series power flow, are also demonstrated allowing a little in-house coding around existing tools routinely used by DSOs. This allows easier solution of some problems without developing new tools in the initial stage of transitions from present practice.

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APPENDIX: THE GREDOR STATE ESTIMATION APPROACH [27]

Lack of real-time measurements (SCADA) is inherent to almost all distribution systems. Usual approach to cope with this issue is to create pseudo-measurements to restore system observability and treat these measurements as low accuracy in the problem formulation. On the other hand, more and more smart meters are installed in LV systems. Taking advantage of such measurements in state estimation offers several difficulties: model of LV system is hard to obtain, even if the model is available its consideration would considerably increase computational burden, and since smart meters are slow reporting rate measurements their inclusion would require a special care in the problem formulation. The approach adopted in the GREDOR project is to use both available SCADA measurements at MV and smart meters at LV level while avoiding modelling of LV network. A new state estimation is described in [27] and illustrated in Fig. 18. It is based on the assumption of a strong correlation among loads of the same type (residential, commercial, etc.) within the same area [27].

The proposed approach accounts for distribution generation at LV level, which is important in view of the rapid growth of PV installations connected to LV networks. It by-passes the use of pseudo-measurements by expressing the MV bus injections as functions of a small number of active power components at LV level, treated as additional state variables.

The whole active power consumed at LV level is split into c_D demand components, one for each type of load, (residential, tertiary sector, industrial, etc.). Similarly, the whole active power generated at LV level is split into c_G DG components. In today's LV networks, the dominant DG units are PV installations, but other types can be included.

Let $c = c_D + c_G$ and L be the number of MV bus injections corresponding to connections to LV networks.

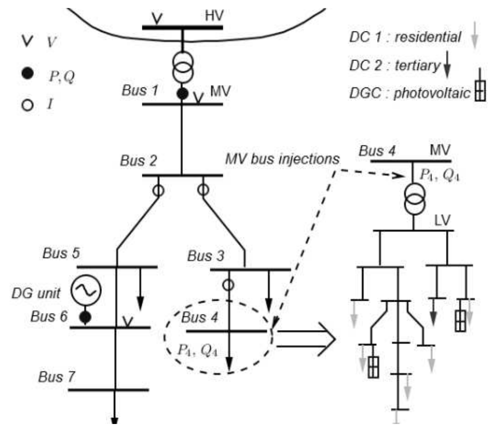

Fig. 18: The idea of new state estimation (adopted from [27]).

In illustrative example of Fig. 18 for a simple synthetic MV system $L = 4$ since there are connections to LV networks at buses 3, 4, 5 and 7. The LV grid fed by bus 4 is also sketched. It supplies two types of loads, respectively residential and tertiary sector, and hosts PV units. The same holds true in the LV networks connected to buses 3, 5 and 7. In this example, $c_D = 2$ and $c_G = 1$.

The demand and DG components contribute to the L MV bus injections of the distribution system. Let ξ_i $(i = 1, \ldots, c)$ be the active power consumed by all loads, or produced by all generation units of the same component, with $\xi_i > 0$ for a demand component and $\xi_i < 0$ for a DG component. These variables are grouped into: $\boldsymbol{\xi} = [\xi_1, \xi_2, \ldots, \xi_c]^T$.

It is assumed that the relationship between the active and reactive power injections P_ℓ and Q_ℓ at the ℓ-th MV bus and the ξ_i variables can be expressed through a general non-linear model,

$$P_\ell = \varphi_\ell(\boldsymbol{\xi}), \quad \ell = 1, \ldots, L \tag{18}$$

$$Q_\ell = \psi_\ell(\boldsymbol{\xi}), \quad \ell = 1, \ldots, L \tag{19}$$

In order to account for losses in LV networks and MV/LV transformers the quadratic formulas are proposed in [27]:

$$P_\ell = \sum_{i=1}^{c} \alpha_{\ell i}\xi_i + \alpha_\ell \left(\sum_{i=1}^{c} \xi_i \right)^2 \tag{20}$$

$$Q_\ell = \sum_{i=1}^{c} \beta_{\ell i}\xi_i + \beta_\ell \left(\sum_{i=1}^{c} \xi_i \right)^2 \tag{21}$$

Two issues to be addressed include: identification of the parameters $(\alpha_{\ell i}, \alpha_\ell, \beta_{\ell i}, \beta_\ell)$ from smart meter data (possibly complemented with some knowledge of the model), and how Eqs. (20,21) can be handled in the state estimation formulation. In [27] the parameters are identified using smart meter recordings and an efficient sampling technique, while the equations 20,21 are considered as equality constraints in the state estimation solved using Hachtel's augmented method (known for its robustness and efficient handling of the constraints). Full details on the proposed state estimation together with results using a small synthetic MV system with LV smart meter data provided by ORES, can be found in [27].